Appendix A

Report on the
Adequacy of the T&D Systems of
Maine's Four Major Electric Utilities

Presented to:

Public Utilities Commission
State of Maine

By:

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I. Introduction and Background

A. Background of the Study

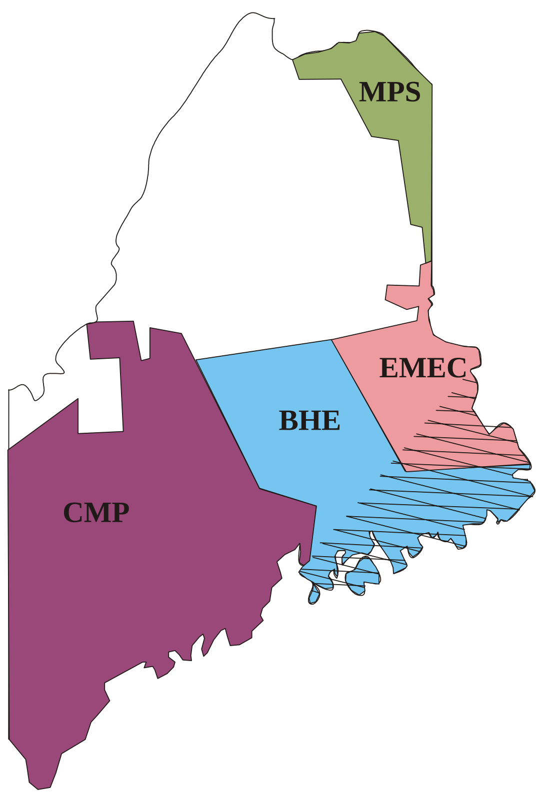
The Committee on Utilities and Energy of the Maine Legislature directed the Maine Public Utilities Commission (Commission) to evaluate issues related to the safety and reliability of Maine's transmission and distribution system. In a request for proposals dated April 22, 2004, the Commission sought technical assistance in carrying out this directive. The Commission chose The Liberty Consulting Group (Liberty) to provide this assistance.

B. The Major Maine Electric Utilities

In addition to nine relatively small municipal distribution companies, there are four larger electric companies in Maine that in the aggregate serve approximately 90 percent of Maine's energy requirements:

- Central Maine Power Company (CMP)
- Bangor Hydro Electric Company (BHE)
- Maine Public Service Company (MPS)
- Eastern Maine Electric Cooperative (EMEC).

The map shown below shows the approximate service territories of these four utilities. The hatched area approximates Washington County, an area mentioned by the legislative committee.



These four utilities are quite dissimilar. CMP has over three times the number of customers and peak load as the total of the other three and serves the more populated areas in southern Maine. CMP's average number of customers per square mile of territory is over twice that of the next highest. BHE is the second largest utility in the state and serves the Bangor/Brewer area and most of rural Washington County. MPS is the third largest utility in Maine and its service territory is principally rural northern Maine. EMEC, Maine's fourth largest utility, is a small electric cooperative that serves rural eastern Maine and parts of Washington County.

	# Customers[1]	Peak Load (MW)	Area Served (sq. miles)	Customer Density
CMP	568,000	1,514	11,000	52
BHE	112,150	300	5,300	21
MPS	35,618	138	3,600	10
EMEC	12,076	28	3,000	4

It is apparent that the overall safety and reliability of Maine's transmission and distribution system is largely dependent on CMP. Moreover, because of the size and loading of CMP's transmission and distribution system compared to that of the other three utilities, one should expect the sophistication of CMP's methods and tools to meet a higher standard than those employed by the others.

Another difference among these utilities is that CMP and BHE are members of the New England Power Pool (NEPOOL) control area, while MPS and EMEC are part of the Maritime Power Pool control area. MPS and New Brunswick Power Company supply the transmission requirements for EMEC. Wheeled energy through the New Brunswick power system is the only way for MPS and EMEC to use energy from the NEPOOL Region.

C. Scope and Nature of Liberty's Study

Liberty began its assistance to the Commission on this study in July 2004. Liberty had the opportunity to submit questions and requests for information through the Staff of the Commission to all of the utilities. Liberty also had the opportunity to interview key employees of the utilities to gain additional insight on their methods and processes. Nevertheless, Liberty's review was diagnostic in nature. That is, Liberty covered a broad range of topics in a relatively short period of time looking especially for both good practices and for potential trouble spots, or "red flags" of potential problems and areas needing improvement. To provide more definitive conclusions and recommendations would require a more in-depth study of these widely diverse utilities.

The areas that Liberty examined generally fall into the following categories:

- Budgeting and Expenditures
- System Reliability
- System Planning, Design, and Equipment Ratings
- Inspections, Maintenance, and Vegetation Management.

[1] Utilities count the customers by meter or account and not by the number of individuals served. A typical residential home counts as one customer.

Liberty organized this report by utility and by the above topic areas.

Liberty is well qualified to examine service reliability issues, having done so on more than ten occasions for public service commissions and for two major electric distribution utilities. For example, following highly publicized outages in the city of Chicago during the summer of 1999, the Illinois Commerce Commission (ICC) retained Liberty to perform a comprehensive investigation of the reliability of Commonwealth Edison's T&D systems. The ICC then retained Liberty to investigate an additional outage that took place and again to verify that Commonwealth Edison appropriately implemented the recommendations resulting from internal and external investigations.

Liberty's team for this study included senior, experienced personnel. Liberty's team included the engagement director for Liberty's prior T&D audits and outage investigations, the former Chief Engineer of the New Hampshire Public Utility Commission, and the former owner of a national electrical equipment testing and failure investigation firm.

D. Common Issues

Terminology

Liberty has attempted to write this report so that those not familiar with technical aspects of electric transmission and distribution systems could understand it. In some cases, Liberty uses footnotes to explain terms or specific matters.

The transmission system is the overhead and underground high-voltage lines, substations, and other electrical equipment that are used to deliver electricity from generating stations to the distribution system. Typical transmission systems carry electricity between 34,500 and 765,000 volts. The distribution system is the overhead and underground lines and other electrical equipment used to deliver electricity from the transmission system to customers. Distribution systems typically use voltages from 12,500 down to the low voltages supplied to customers. Maine's utilities use 34,500 volt systems for both distribution and sub-transmission.

Substations contain transformers and other electrical equipment. The functions of substations are to change the voltages in the electric delivery system and to connect generating stations, the transmission system, and the distribution system.

The National Electrical Safety Code (NESC)

One issue that Liberty found common at least to some extent among the four utilities was compliance with the NESC. The NESC is an American National Standards Institute (ANSI) standard with a consensus of those substantially concerned with its scope and provisions, including the Institute of Electrical and Electronic Engineers (IEEE). The NESC includes various provisions for the safeguarding of persons from hazards from the installation, operation, and maintenance of electric supply lines and equipment. The NESC is voluntary; however, many commissions throughout the United States have adopted it for application within their jurisdictions. The Maine Commission has adopted the NESC within its jurisdiction.

Parts of the NESC address equipment deterioration. The NESC recognizes that facilities placed in service have various opportunities and propensities to wear, break, become damaged, or otherwise have conditions adversely affect them such that continued serviced in that state would be inappropriate for safety reasons.

Sections 253 and 261 of the NESC provide the required strengths of electrical structures and the "at replacement" strength levels that indicate when utilities should replace or rehabilitate structures such as poles.

Section 214A of the NESC requires that utilities inspect energized lines and equipment at such intervals as experience has shown to be necessary; and that when considered necessary, utilities should subject lines and equipment to practical tests to determine required maintenance. The NESC states that a utility should promptly repair, disconnect, or isolate defects that it could reasonably expect to endanger life or property. Furthermore, utilities should maintain records of any defects affecting compliance with the code revealed by inspections or tests until it corrects the defects.

Looping

One aspect of the design of a T&D company's system that Liberty examined was "looping." In general, looping provides enhanced reliability through redundancy for serving customers or parts of the system by more than one electrical source. Utilities can do this at the transmission level by the use of multiple transmission lines and at the distribution level through ties between different distribution circuits and feeders.

Equipment Age

Although age contributes, in varying degrees, to equipment deterioration, other factors, such as environment exposure and excess mechanical and electrical stresses, influence the extent of equipment deterioration. To ensure adequate and safe operational condition, utilities should inspect equipment for deterioration and faulty components, and should maintain the equipment until either it cannot be repaired, or it is not cost effective to continue maintenance activities on the equipment. One goal of an inspection and maintenance program is to identify when the utility needs to replace equipment based on condition, and not just on age. Aged equipment typically requires inspection and maintenance more often than newer equipment, but age alone does not determine the condition of equipment.

E. Conclusions & Recommendations

The following major sections of this report provide a summary of Liberty's review of each of the four Maine electric utilities. Each of these sections notes any areas that Liberty believes could be matters of concern with regard to the reliability of the utility's transmission and distribution systems. Liberty more fully explains its reasons for concern in those specific sections.

Overall, Liberty did not identify major issues related to the transmission systems for the utilities. However, none of the four utilities fully complied with the NESC-required inspection and pole testing requirements for distribution circuits.

Liberty performed its review at a high level to determine if there were warning signs of precursors to reliability problems. Liberty found that inadequate record keeping, inadequate distribution inspection programs, uncorrected circuit overloads, and the distribution system vegetation management program at CMP rose to that level of concern. Liberty believes that CMP recognized these issues but did not take appropriate action to correct them. Liberty expected the largest electric utility in Maine and the fourth largest in New England to maintain its distribution system in the same excellent manner as it maintains its transmission system. Accordingly, Liberty recommends that the Commission consider performing a more in depth review of the entire CMP distribution system to address these concerns.

Although BHE and MPS also exhibit weaknesses, those weaknesses do not rise to the same level of concern. When BHE merged with Emera, it performed a complete review of its distribution system, recognized weaknesses, and has been taking action to correct deficiencies. Similarly, MPS, on its own initiative, instituted an outside review of its system and has been taking corrective action on the deficiencies found. The RUS audits EMEC every three years. Those audits show that EMEC is also taking action to correct recognized deficiencies. Liberty does not recommend additional reviews of these utilities.

With regard to looping, the service territories of Maine's utilities are not conducive to providing looped service at the distribution level except where higher concentrations of load exist. The utilities appear to be looping distribution where appropriate. Utilities provide looping at the transmission level by setting standards that allow no more than a fixed amount of load to be lost for a single transmission contingency (failure). There is no industry standard but many utilities use 25 MW for this purpose. BHE set this standard at 50 MW and Liberty considers this value too high compared to that used by other utilities both within and outside of Maine. Liberty recommends that the Commission consider ordering BHE to have this value reviewed and file a report on the outcome of that review.

With regard to looping the transmission feed to the EMEC system, Liberty notes that the EMEC load, while greater than 25 MW, includes interruptible load. Considering firm load, the EMEC load is 20 MW at most. Transmission lines of about 50 miles in length from either New Brunswick or BHE would be necessary to provide looped transmission feeds to EMEC. Either would be very expensive and most likely not supportable by such a small load.

The following is a summary of the major issues identified for each utility:

Central Maine Power Company (CMP)

- CMP does not have a distribution pole testing program to verify whether it has poles that fail to meet strength requirements of the NESC. CMP should periodically test the strength of its distribution poles. CMP should promptly identify and schedule replacement or reinforcement of poles that do meet the NESC strength requirements. Also, CMP indicated that it did not plan to implement a periodic distribution circuit inspection program or a distribution pole inspection and testing program. This does not comply with the NESC. Considering the size and resources available to CMP, Liberty would have expected it to be a leader in Maine with respect to NESC compliance. Allowed to continue, the lack of a sound inspection program with good record keeping could lead to both reliability and safety problems. Good record-keeping practices also can aid equipment failure analyses, planning, and design.

- CMP's current distribution vegetation management (tree-trimming) program is reactive, acting only on those circuits have had poor tree-related performance. The program's only objective is to meet the overall, short-term reliability levels required by the ARP (alternative rate plan). It addresses only segments of 10 to 20 circuits that have already experienced tree-related problems. For long-term reliability improvement, CMP should revise its vegetation management program to be predictive. That is, CMP should either inspect all circuits for tree-trimming needs (including a time buffer to allow for fast growth) and trim circuit segments before trees cause outages, or have a cyclic system-wide program that allows for differences among the growth rates of various tree species. Also, because CMP's contractor performs tree-trimming work on a unit bid basis, CMP should consider inspecting 100 percent of the contractor's work. Here again, neglected tree trimming has the potential to lead to reliability and safety problems.

- CMP is allowing, without planned reinforcement, at least two of its distribution circuits to operate during forecast peak load days at about one and one-half times the circuits' ratings. This is not good utility practice. CMP should construct feeder reinforcements to prevent possible overloading such as these from occurring. While circuits may operate satisfactorily for a period of time in an overload condition, this practice will reduce the expected lives of equipment in the circuit and increases the potential for prolonged outages.

Bangor Hydro Electric Company (BHE)

- BHE limited its distribution circuit (and roadway transmission) inspection program to circuits in its vegetation management program. The inspection program is not periodic and does not include testing poles for strength, both of which the NESC requires. BHE should implement its planned cyclic distribution circuit inspection program and include pole testing. It should also include pole treatment, which would extend useful pole life. Prior to 2002, BHE used an informal ownership approach to circuit maintenance. BHE now recognizes the need for a more structured and formal circuit inspection program and is now developing one.

- BHE's transmission reliability criteria allow a single contingency (failure) to interrupt load for up to 50 MW. When compared to its 300 MW of total load and practices used by other utilities, this amount appears excessive. Lowering the 50 MW criterion may result in requiring BHE to provide more transmission system looping and thus improve system reliability.

- BHE applies distribution reliability and maintenance programs to its roadside transmission circuits. BHE should either separate its roadside transmission plant from its distribution plant when conducting its reliability and other maintenance programs or otherwise ensure roadside transmission receives the same level of inspection and maintenance as provided for in the transmission programs.

Maine Public Service Company (MPS)

- Although MPS's distribution cedar pole replacement program and the new, intensified, and specific distribution inspection and pole test program are good, the programs do not fully comply with paragraphs 121 and 214 of the NESC, which require total-system, periodic inspection and tracking of identified defects. Liberty agrees with MPS that it should implement a formal and periodic distribution circuit inspection and repair program, including tracking of defects until repaired. However, it should also include pole treatment in its pole testing program, which would extend useful pole life.

- MPS brought tree trimming in-house and thus has the capability to perform work on lines and tree trimming with some of the same crews. Liberty agrees with MPS that, for long-term reliability, it should implement a proactive 5-year tree trimming cycle on its distribution circuits while performing hot spot trimming on its worst performing circuits. It should also determine the necessity of obtaining easements for roadside trimming. There could be cases in which MPS cannot provide appropriate clearances and therefore risk more tree-related outages if it does not have these easements. Or, if MPS is providing adequate clearance, it is trimming trees on private property without landowner consent.

- MPS is not analyzing the causes of its substation bus outages, nor is it analyzing the trends in the failure of line equipment causing circuit outages. MPS should analyze the root causes for bus lockouts and identify common circuit equipment failure modes, and take actions as required to minimize outages. Substation buses serve multiple distribution circuits; thus bus outages can affect many customers.

Eastern Maine Electric Cooperative (EMEC)

- EMEC's distribution circuit inspection programs do not fully comply with paragraphs 121 and 214 of the NESC, which requires total-system, periodic inspection and tracking of identified defects. EMEC should implement a formal and periodic distribution circuit inspection and repair program, including tracking of defects until repaired. It should also include pole treatment and replacement in its pole testing program, which would extend useful pole life.

- EMEC could improve system reliability with a more robust vegetation management program.

- EMEC has experienced about 20 substation bus outages per year. EMEC should perform a root cause analysis of its substation bus outages and determine actions to minimize these outages.

- EMEC has no on-system generation; a single 44 kV line from the southern part of the MPS system partially supplies its energy. This line has a significant effect on EMEC's reliability. Liberty suggests that EMEC report to the Commission and MPS supply outage data for determining and monitoring the reliability effect on EMEC. EMEC should be proactive in its involvement with MPS' transmission planning and changes that could affect EMEC.

II. Central Maine Power Company (CMP)

A. Budgeting, Expenditures, and Other Issues

CMP is the largest electric utility in Maine and the 4th largest in the New England area. It is about five times the size, in terms of number of customers and load, than the next largest Maine utility.

CMP is one of five electric distribution companies that make up Energy East. Energy East also has a service company that provides financial, human resources, and purchasing services for the operating companies. Liberty did not review Energy East's overall budgeting and whether CMP's shares fairly in the allocation of resources.

CMP has formal budgeting guidelines. The process uses T&D design criteria as a trigger point for determining the need for particular projects. CMP also prioritizes projects on the basis of safety, statutory requirements, customer requirements, serious maintenance needs, the firm's long term strategy, and operational flexibility. Each proposed project has a sponsor. The capital budget for CMP in 2004 was down from earlier years because there was no construction connected with new generators. Distribution system capital spending relates to reliability improvement needs for ten under-performing circuits, some other selected circuits, and looping design improvements.

CMP uses its Economic Assessment Tool to analyze discretionary capital projects estimated to cost more than $100,000. This tool basically performs a net present value analysis to put competing projects on a common basis.

CMP's O&M budgeting process is similar to that used for capital expenditures. The budgeting starting point is historic levels, and CMP makes additions or cuts on a regional basis. The O&M budget was down 5 to 10 percent in 2004 with some of the reduction in vegetation management.

CMP said that it prioritizes its O&M work, and some of its capital work, to achieve service quality targets established in the Alternative Rate Plan as well as to improve the performance of its under-performing circuits.

CMP has funded programs involving new technologies. They have replaced old electromechanical relays with microprocessor-based relays, applied fiber optics for relay communications, PLC control of automatic line reclosers, and satellite clocks to synchronize transmission line relaying.

B. System Reliability

CMP's overall interruption frequency and duration indices have increased in recent years, but show a decrease (improvement) after CMP makes exclusions for major storms. The major storm exclusions up to 2003 were for events affecting 10 percent or more of customers based on service centers and therefore had a potential to exclude events that normally would be included when calculated on a total system basis. This phenomenon can also occur if a utility considers more storms as "major" as a result of poor system performance in relatively minor storm conditions. CMP was able to provide a good tabulation of equipment failure types that caused service interruptions. However, equipment failures have increased by 42 percent from 2001 to 2003. Failed transformers accounted for most of the increase in interruption duration. Human errors also saw a significant increase due to motor vehicle accidents. CMP keeps track of momentary service interruptions. CMP only designates trees as the outage cause when that is certain to have occurred. It is possible that inadequate tree clearances actually caused many of the outages designated as caused by storms, wind, or unknown as well as those designated as caused by trees.

CMP has transmission, distribution, and substation inspection and maintenance programs as described in Section IV D below, and it repairs defects found by its inspections to improve the condition of its transmission and distribution systems. However, only its worst feeder vegetation management program provides for real distribution reliability improvements. CMP does not have a comprehensive worst performing circuit program that analyzes all causes of outages and deals with identified problems.

CMP's distribution design includes coordination schemes with the fusing of side taps and the use of mid-point reclosers. These distribution protective devices can help provide improved reliability by limiting the number of customers affected by a fault. CMP uses fault indicators to help troubleshoot the sources of problems thus reducing outage duration.

CMP has much of its transmission and distribution systems SCADA[2]-controlled, which helps provide for improved reliability and efficiency. Of its 92 substations with transmission assets, 72 have full SCADA control. Of the 197 substations with distribution assets, 64 have full SCADA control. The remote control provided by SCADA can improve reliability by limiting service interruption durations.

C. System Planning, Design, and Equipment Ratings

CMP has a formal and thorough system for evaluating equipment ratings for all types of transmission equipment and under many different ambient conditions. It calculates transformer loss-of-life and has excellent rating tables. In rating its distribution system, CMP uses the rating of the circuit conductor. CMP states that it sizes all other components to the few standard conductors used.

CMP has formal planning criteria and it loops its transmission system such that there is a loss of no more than 25 MW for a single outage and the loss of no more than 60 MW for a double contingency outage for load levels below 85 percent of peak (maintenance outage criteria). For its bulk power system, CMP follows NEEPOL (New England Power Pool) and NPCC (Northeast Power Coordinating Council) requirements.

Using state-of-the-art computer programs, CMP performs all types of transmission system transient stability, load flow, and other studies that one would expect for a large electric utility. It

[2] SCADA, or supervisory control and data acquisition, is useful for providing operational data and control for capacity planning, circuit breaker control, and system monitoring.

studies seasonal peak and minimum load levels and performs its planning studies by areas within its system. CMP also performs operational studies for load power factor correction and to monitor operational performance. CMP uses a one-in-ten year weather normalization to forecast load on its transmission studies, as required by NEPOOL. This practice helps assure that actual loads will not be higher than forecasted loads during extreme weather conditions.

Load growth and power quality issues are the main drivers for distribution system improvements. CMP uses a modeling software tool that assumes a voltage at the starting bus. Many of CMP's urban distribution circuits are looped. The company stated that it starts to formulate solutions when circuit loading reaches 80 to 90 percent of circuit rating. However, information provided by CMP indicates that CMP is not fully complying with its criteria. A CMP report showed that there are several circuits forecasted to be loaded on peak days up to 146 to 165 percent of ratings. CMP indicated no year 2005 circuit improvement plans for these circuits in the report, and there was no indication of how long these circuits might have been overloaded. Such large overloads generally take many years to develop.

CMP's distribution load forecasting methods appeared to be adequate. However, it used only average weather conditions to normalize historical loads. In extreme weather conditions, the loads on distribution circuits could be higher than planned and result in service outages.

CMP does not have a formal looping or circuit tie criterion for its overhead distribution circuits. However, it does have a formal looping criterion for its underground residential distribution cable circuits.

D. Inspection, Maintenance, and Vegetation Management

CMP's transmission line inspections include line foot patrols on a 10-year cycle (except for the 345 kV transmission, which is annual), a climbing inspection every four years, helicopter patrol every spring, and tower base inspection/repair on a 20-year cycle. The 10-year transmission pole inspections include a ground-line inspection, soundings to identify poles with insufficient strength, and the application of treatment to extend pole life. CMP's goal is to complete all transmission inspections and maintenance every year. The company indicated that it completes Bulk Power stations as required by NPCC and completes non-bulk power stations close to 100 percent. CMP's transmission inspection program complies with NESC requirements.

CMP's distribution inspection programs include an annual three-phase circuit infrared inspection program, an informal circuit inspection (by employees while performing their regular duties and by its meter readers), and a recloser inspection program. In the late 1990s, CMP began to move away from its formal 5-year distribution line inspection program, and ceased the program in about 1999. CMP does not inspect every distribution pole on its system at a periodic interval, nor does it verify that pole strengths meet NESC requirements. The NESC requires both periodic equipment inspections and the maintenance of pole strength to prevent system deterioration or unsafe conditions from materializing.

CMP inspects substations either monthly or every other month depending on the voltage and performs infrared examinations of substations once a year. CMP has a comprehensive substation testing and maintenance program. It was the only Maine utility that routinely tested the substation ground grid. Maintenance item completion rates have been nearly 100 percent for the last few years, and CMP indicated that it has a new work management system coming on-line soon.

CMP's transmission system includes approximately 33,400 acres of right-of-way. Transmission vegetation management is on a 4-year cycle and includes danger trees and side trimming. CMP inspects vegetation on transmission lines every four years. Transmission system vegetation management appears to be very satisfactory.

However, the distribution system vegetation management has varied over the years. From 1989 to 1995, CMP implemented some of a consultant's recommendations and considered, but never implemented, the recommended 5-year regular vegetation management cycle. From 1995 to 1999, CMP used a "matrix approach" that it based on outage history and brush conditions. It also experimented with trimming entire circuits in one to two consecutive calendar years. CMP called 1999-2000 "transition" years in which it created an annual plan and prepared for the new Alternative Rate Plan (ARP). For the years 2001-2004, CMP developed an annual plan using its interruption frequency index by work area as the primary determining factor. Liberty views this approach to vegetation management as reactive in nature because it requires reliability problems to surface before they are addressed. CMP annually funds vegetation management work on segments of 10 circuits with poor tree-related reliability to meet the ARP requirements. CMP said that it also funds tree trimming work on another 10 circuits. With over 400 circuits in its system, this amount of tree trimming is relatively small. It does not trim trees on a proactive cycle plan. CMP said that the vegetation management standard ANSI A300, draft dated September 18, 2004, section 73.3, indicated that "[v]egetation maintenance cycle should be avoided." However, this statement relates to minimizing stress on vegetation in right-of-ways in general and is not applicable to the need to provide reliable electric service for customers served by roadside distribution lines. CMP performs its trimming by line sections. One contractor performs all vegetation management on a bid basis and CMP inspects 10 percent of the contractor's work. CMP does not provide a fast growth buffer so that fast growth will result in the circuit performing poorly more quickly. CMP's distribution tree trimming practices can lead to reliability problems when trees contact lines causing outages and when intermittent tree contact causes momentary interruptions.

E. Conclusions

Liberty found that CMP plans and maintains its substations and transmission lines consistent with other utilities of similar size. The transmission system inspection and pole-testing programs are in compliance with NESC, and the proactive vegetation management and equipment maintenance programs should help provide adequate transmission reliability. Also, the way CMP plans its distribution system and how it performs some specific maintenance tasks, such as its annual distribution system infrared inspections and recloser inspections, are also proactive activities that promote reliability.

However, Liberty identified several important issues related to CMP's distribution system. The following are brief discussions of these issues:

- CMP does not have a distribution pole testing program to verify whether it has poles that fail to meet strength requirements of the NESC. CMP should periodically test the strength of all its distribution poles. CMP should promptly replace poles that do meet the NESC strength requirements. Also, CMP indicated that it did not plan to implement a periodic distribution circuit inspection program or a distribution pole inspection and testing program. This plan does not comply with the NESC. Considering its size and the resources available to CMP, Liberty would have expected it to be a leader with respect to NESC compliance.

- CMP's current distribution vegetation management (tree-trimming) program is reactive, acting only on those circuits that have had poor tree-related performance. The program's only objective is to meet the overall, short-term reliability levels required by the ARP (alternative rate plan). It addresses only segments of 10 to 20 circuits that have already experienced tree-related problems. For long-term reliability improvement, CMP should revise its vegetation management program to be predictive. That is, CMP should either inspect all circuits for tree-trimming needs (including a time buffer to allow for fast growth) and trim circuit segments before trees cause outages and power quality problems, or have a cyclic system-wide program that allows for differences among the growth rates of various tree species. Also, because CMP's contractor performs tree-trimming work on a unit bid basis, CMP should consider inspecting 100 percent of the contractor's work.

- CMP is allowing, without planned reinforcement, at least two of its distribution circuits to operate during forecast peak load days at about one and one-half times the circuits' ratings. This is not good utility practice because it will shorten equipment lives and can cause interruptions in service. CMP should construct feeder reinforcements to prevent possible overloading such as these from occurring.

Liberty also identified the following minor issues related to CMP's distribution system:

- CMP bases its worst performing circuit program on tree-related problems. It does not have formal programs to address other specific outage causes, such as animal and equipment related outage causes. It should formally analyze the cost-reliability benefits of the corrective actions required for each type of outage cause and include these actions appropriately in its worst performing circuit program.

- CMP's uses average weather conditions to normalize historical loads. It should consider the use of loads in its system studies based on a probabilistic expectance of occurrence. This will provide more accurate investment timing.

III. Bangor Hydro Electric Company (BHE)

A. Budgeting, Expenditures, and Other Issues

BHE's policies and practices related to T&D capital and O&M spending are largely unwritten. The company indicated that it establishes priorities on the basis of such considerations as regulatory matters, reliability-driven projects, minor rebuilds for improvement of existing distribution plant, growth to meet capacity, and miscellaneous projects. Inspection results primarily drive O&M initiatives. That is, the findings from BHE's inspections of its system are a primary determinant of where BHE plans to spend money on maintenance. BHE establishes, funds, and resources programs to meet performance targets established by its Alternative Rate Plan (ARP) or other internal measures. BHE expects its managers to execute these programs within established budgets. However, BHE's management indicated that it has funded programs to improve effectiveness and efficiencies, as well as provide for long-term reliability. Examples are the automatic meter-reading program, funding for additional SCADA equipment, and upgrading to state-of-the-art maintenance management software programs. Management indicated that its goals were not only to meet ARP reliability levels, but also to be the "best" utility in the area.

BHE uses the estimated cost per avoided customer-hour of service interruption to evaluate and rank proposed reliability projects.[3] BHE includes only the highest ranked projects in the budget. All other expenditures must be justified. This practice has the potential for excluding necessary inspections and routine maintenance. BHE recognized that its ranking system also has the potential to penalize rural circuits that may have few customers, and indicated that it plans to make appropriate changes.

BHE tracks the results of reliability improvement programs to determine whether the results were as expected. Also, BHE has a formal, centralized asset management system that includes projected and actual capital and O&M expenditures.

BHE indicated that its new, proposed 345 kV transmission line would not affect the regular budgeting process or its funding levels.

B. System Reliability

BHE's interruption frequency and duration indices have increased since 2001. The company attributes much of this increase to its new computer-based outage management system that is more accurate than that previously used. After excluding major storms, BHE reported that weather still accounted for about half of the customer interruptions and more than half of the interruption minutes. Distribution equipment failures accounted for about 14 percent of the customer interruptions in 2002 and 2003.

[3] For example, if Project A costs $100,000 and will save 1 hour of service interruption for 100 customers ($1,000 per customer-hour) and Project B costs $50,000 and will save 10 hours of service interruption for 1 customer ($5,000 per customer-hour), Project A ranks higher than Project B.

To meet the reliability indices required by the Alternative Rate Plan, BHE has undertaken reliability programs (other than inspection and maintenance work) on selected circuits. In 2002, BHE targeted ten circuits for special vegetation management and the installation of reclosers and sectionalizers. It completed about 85 percent of planned reliability improvement work by year-end 2002. In both 2003 and 2004, BHE selected 20 circuits for vegetation management and protective device installation. It completed over 95 percent of the reliability work targeted on the 20 circuits by year-end. BHE included in this reliability work the correction of various pole and hardware defects identified during vegetation inspections.

From its tracking of outage causes and for its distribution inspection program, BHE identified additional specific actions to apply to its worst performing circuits in 2004 and 2005 to improve reliability. These targeted programs include replacing a type of 15 kV dead-end insulator, fused cut-out switches, brackets for covered conductors, and the installation of animal guards.

When complete later this year, the work on the 50 circuits included in the 2002, 2003, and 2004 programs will have affected the reliability of service for two-thirds of BHE's customers.

To improve the reliability of its transmission system, BHE conducted a lightning arrester replacement program during 2002 and 2003. It replaced all of the specified transmission lightning arresters (105) during that period. For 2004, BHE targeted specific tree-trimming work on transmission lines with poor reliability due to tree-related problems.

BHE has SCADA on all 13 transmission substations, 9 of the 15 urban distribution substations have SCADA, and 16 of the 43 rural distribution substations have SCADA. BHE appears to use SCADA, particularly for its distribution circuits, more than other utilities of similar size.

C. System Planning, Design, and Equipment Ratings

BHE has not performed new transmission planning studies since 1996. However, it reported that a 2004 study is in progress. BHE's transmission reliability criteria are that a single contingency should not exceed the loss of 50 MW, not cause a loss of 25-50 MW for more than two hours, and not cause a loss of less than 25 MW for more than 24 hours. The 50 MW limit appears to be too large for a company of this size. BHE uses transmission system looping to help meet these criteria. However, BHE's 69 kV line that supplies most of eastern Maine does not meet the lowest level of these criteria. BHE has plans for the construction of a second 69 kV transmission line into this area of their system to form a transmission loop. Although such a line would increase reliability, its cost may be unacceptable to ratepayers.

BHE's transmission load forecasting uses historical peak loads normalized to average weather conditions (heating and cooling degree-days). It also considers external factors such as large, specific changes in known load. This weather normalization practice might lead to an underestimation of loads when compared to probabilistic methods and unforeseen overloaded system conditions.

BHE uses commercially available software to analyze its distribution circuits, and has 5-year distribution plans for the Bangor-Brewer area based on the analyses performed. In general, BHE's circuits are not heavily loaded; only one circuit in 2004 was loaded in excess of 90 percent of ratings. BHE only uses looping and ties[4] on the distribution system in the Bangor-Brewer area because the remaining area is rural. Extending circuits in rural areas for tying is expensive and likely not cost effective.

BHE forecasts distribution load by knowing the connected kVA (as indicated by the GIS mapping system), and from bi-monthly substation load data (from substation inspections and SCADA). Other utilities use similar approaches.

Often, utilities fail to consistently apply fuses on taps off of main distribution circuits. Typically, this is a cost-effective way to improve the service interruption frequency to many customers. However, BHE typically fuses its taps and coordinates them with upstream reclosers.

There is evidence that BHE proactively evaluates its line and equipment ratings. For example, BHE reported to Staff that it is re-conductoring two lines because of the ambient temperature assumed in the rating analysis. BHE construction standards and equipment rating specifications appear to be adequate.

D. Inspection, Maintenance, and Vegetation Management

BHE patrols its transmission right-of-ways from the air by helicopter twice a year. The purpose of these formal inspections is to identify pole and hardware problems, encroachments, animal activity, and vegetation problems. It rates defects identified as priority and non-priority items. BHE reports that it had addressed all priority items identified from all inspections from 1999 to 2003. It also performs climbing inspections as needed to investigate defects identified by the aerial inspections. BHE reports that it plans to start conducting periodic foot patrols to uncover defects hidden from airborne inspectors.

BHE formally inspects, tests, and treats it transmission poles in transmission line right-of-ways on a 10-year cycle to identify poles that do not meet minimum NESC requirements. It rates poles as rejects that can be reinforced, standard rejects, or priority rejects. It replaces priority reject poles immediately and standard reject poles within 18 months. It re-inspects any poles found acceptable but in deteriorated condition after five years. During the last five years, BHE inspected and treated about 50 percent of its 7,707 poles on transmission right-of-ways. In 1999 it rejected and replaced or reinforced almost 5 percent of these poles. In 2003, it identified only 1 percent of the poles as reject poles. Roadside transmission poles (about 11,300) are not included in the transmission right-of-way inspection program.

BHE had no formal distribution circuit inspection and maintenance programs before 2002. Informal inspections resulting from a circuit ownership program primarily drove distribution pole line maintenance. In August 2002, BHE started a formal walking/driving distribution circuit inspection program. However, it conducts this formal inspection program only on those circuits inspected as part of BHE's distribution vegetation management program. BHE's distribution circuit inspection and maintenance program is not periodic, it does not include the testing of poles to identify reject distribution (and roadside transmission) poles, and it does not include the

[4] Ties are locations on the distribution system where two circuits are in close proximity to and in phase with each other, and equipment exists that allows for the transfer of load from one circuit to the other.

treatment of poles to extend pole life. Because the distribution inspection and maintenance program does not include periodic inspections of all circuits, and does not include tests to verify pole strength, BHE is not in full compliance with Commission and minimum NESC safety requirements. However, BHE recognizes that its distribution circuit inspection program is reactive, rather than proactive. It reports that it is developing a comprehensive cycle-based (possibly 6 years) inspection program. BHE should include pole testing and treatment in this program.

BHE formally inspects its bulk power substations weekly and other substations monthly. Since 2000, BHE tracks substation corrective maintenance items in its computer maintenance management system. In 2003, BHE completed about 78 percent of the corrective maintenance work identified. The electric department superintendent reviews any deferred work.

BHE maintains about 1600 relays and 40 communication channels in its bulk power, transmission, and distribution systems. It tests the 300 bulk power relays on maintenance cycles set forth by NPCC criteria. It tests other relays on a 5-year maintenance cycle, except non-NPCC relays at 345 kV substations that it tests on a 4-year cycle. Generally, it tests communication channels on a 2-year cycle. BHE reports that its documented relay maintenance completion rate for 2003 was 100 percent. BHE complies with all power pool relay and communication channel testing requirements.

BHE's substation and distribution equipment testing and maintenance programs are extremely comprehensive and thorough, and generally consistent with those found at much larger utilities. BHE tracks its substation and distribution equipment maintenance programs on state-of-the-art computer maintenance management software (CASCADE). Also, BHE reports that the 2003 documented equipment maintenance completion rates were 100 percent.

BHE sprays and trims its transmission right-of-ways on a proactive 4-year cycle. Although, BHE did not perform the 2002 spraying, it resumed spraying in 2003, and it said that it will double the acres sprayed before the end of 2004 to put the transmission vegetation control back on track. Emera acquired BHE in 2002, and it used that year to evaluate best practices, which are now or will be in place.

Historically, BHE trimmed trees on its distribution system circuits and its roadside transmission lines systematically on a proactive 7-year cycle. However, in 2002 to the present, BHE applied a modified trimming program that included targeting sections of 50 distribution circuits identified by the annual system inspection program as sections that were likely to have poor reliability because of tree contact in the future. The inspection includes a one-year buffer period to allow for fast growth years. BHE said that it is continuing its 7-year cycle trimming program while performing proactive "just-in-time" trimming. BHE's vegetation management contractor works on a time-and material basis. This provides flexibility that promotes thoroughness. Also, BHE inspects about 10 percent of the contractor's work to assure that the contractor performs properly.

BHE used sound logic to develop its modified distribution vegetation management program that should maintain reliability and be cost-effective. In 2002, 2003, and 2004 annual expenditures were about 20 percent less than previous years. However, it doubled the annual total miles inspected and evaluated compared to previous years.

Liberty examined BHE's information regarding equipment age and did not identify any specific concerns.

E. Conclusions

Liberty found that most of BHE systems and programs compare favorably with good practices of much larger utilities. Examples of these are BHE's comprehensive reliability improvement programs, proactive vegetation management programs, and superior substation and distribution equipment testing and maintenance programs.

However, Liberty identified several important issues related to BHE's transmission and distribution systems. The following are brief discussions of these issues:

- BHE limited its distribution circuit (and roadway transmission) inspection program to circuits in its vegetation management program. The inspection program is not periodic and does not include testing poles for strength, both of which the NESC requires to maintain safety to the public and utility employees. BHE should implement its planned cyclic distribution circuit inspection program and include pole testing. It should also include pole treatment, which would extend useful pole life.

- BHE's transmission reliability criteria allow a single contingency (failure) to interrupt load for up to 50 MW. When compared to its 300 MW of total load and practices used by other utilities, this amount appears excessive. Lowering the 50 MW criterion may result in requiring BHE to provide more transmission system looping and thus improve system reliability.

- BHE applies distribution reliability and maintenance programs to its roadside transmission circuits. BHE should either separate its roadside transmission plant from its distribution plant when conducting its reliability and other maintenance programs or otherwise ensure roadside transmission receives the same level of inspection and maintenance as provided for in the transmission programs to maintain proper transmission reliability.

Liberty also identified the following minor issue related to BHE's capacity planning.

- BHE adjusts forecast loads using average weather conditions. This practice has the potential for under-forecasting loads and might cause over-loaded circuits in extreme weather conditions. BHE should consider the use of loads in its system studies based on a probabilistic expectance of occurrence. This will also provide more accurate investment timing.

IV. Maine Public Service Company (MPS)

A. Budgeting, Expenditures, and Other Issues

MPS builds its capital and O&M budgets from historical levels. MPS considers factors such as equipment age, circuit loading, and reliability statistics to prioritize budget items. Most budget items are fixed, and flexible capacity projects serve as the float as to whether they are included in the budget to remain in balance with resources. MPS had to defer some capital projects for 2003. However, MPS included scheduled maintenance and tree trimming as part of the base O&M budget. MPS determines O&M expenditures to a large degree on the basis of inspection results.

While MPS does not have a formalized maintenance budgeting process, it does appear to consider all the appropriate factors, reconciles priorities against available resources, and includes necessary maintenance within the budget.

B. System Reliability

MPS's outage cause data indicate that distribution equipment failures and trees were the major causes of sustained customer service interruptions over the last few years. Including major storms (i.e., events that affected a significant percentage of the company's customers), the average customer interruption duration was between one and two hours, and the average customer experienced about two interruptions per year. This value appears reasonable compared to other utilities, especially considering that Maine is one of the most heavily forested states. MPS uses the average of outage times for the last five years as its reliability targets.

MPS keeps track of momentary interruptions (less than 5 minutes) to help identify reliability issues. The number of these momentary interruptions has increased in recent years, but this may be caused by improved methods and tools used to identify this type of service interruption rather than a decline in service quality. MPS installed a system that helps to more accurately monitor momentary outages and can provide more sophisticated data that MPS can use for reliability analysis.

The number of MPS's substation bus lockouts has increased in recent years, particularly in the central area. This is an indicator of a potential problem area, and MPS should identify the causes of substation lockouts and plan the appropriate corrective actions. Also, it does not appear that MPS has a process in place for analyzing and resolving trends in distribution equipment failures that are causing a substantial percentage of service interruptions. MPS should strengthen its analysis of these equipment failures.

MPS has transmission, distribution, and substation inspection and maintenance programs as described in Section II.D below, and it repairs defects found by its inspections to improve the condition of its transmission and distribution systems. However, only its vegetation management maintenance program, and to some degree its cedar pole capital replacement program, provide for real improvement in distribution reliability. MPS does not have a worst performing circuit program. Such a program evaluates outage causes, possible protection coordination changes, and other corrective actions on a cost–reliability benefit basis for each worst performing circuit. MPS should consider the value of developing a worst performing circuit reliability program that includes not only tree trimming but also the tracking of common equipment problems (e.g., cutouts, arresters) and identifying equipment-specific reliability programs to apply to those circuits. However, it is clear that MPS has performed self-assessments[5] and is making changes in its inspection and maintenance programs on the basis of the findings of those assessments.

MPS examines and sometimes uses new technologies that could help efficiency and system reliability. For example, MPS uses a GIS (Geospatial Information System) with electronic mapping, a new asset management program, storm alert software, and microprocessor-based relays. MPS's nine transmission substations are SCADA-controlled, and in 2004, it began installing SCADA in its 28 distribution substations.

In addition to supplying its own customers, MPS supplies EMEC by a radial 44 kV line from the southern part of the MPS system. Therefore, MPS largely controls system reliability for this area of the EMEC system. In the section below on EMEC, Liberty suggests that additional reporting will permit a higher level of scrutiny on the reliability of this line.

C. System Planning, Design, and Equipment Ratings

MPS's transmission, distribution, and substation construction standards appear to be adequate.

Although MPS has informal transmission planning criteria, it performs power-flow[6] modeling for its 20-year plan to prevent voltage problems even if there are two major failures, and it loops its 69 kV system (except where systems are out-of-phase[7]). MPS reported that it has included in its studies the loss of supply from the wood-burning generating plants. MPS has filed with the Maine Public Utilities Commission for permission to construct a new 138 kV transmission line.

MPS does not use power-flow analyses for its 5-year distribution system plans, but mainly depends on customer voltage complaints to identify priority distribution projects. It does not have voltage software to help it predict voltage problems on its distribution system. Also, it forecasts loads on the basis of simple trend forecasts using average weather conditions. MPS should consider using more accurate weather probability analyses in its load forecasting. MPS said that it uses distribution line tie switches at new substations, where practical. MPS can use these switches to supply power from one circuit to another when problems occur and therefore improve system reliability.

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[5] MPS, on its own initiative, had an independent facilities evaluation and engineering audit performed by R. W. Beck.

[6] Load flow analysis is done by the mathematical representation of a power system which allows planners to determine when facilities will be overloaded or when voltages will be inadequate to serve customers.

[7] "Out-of-phase" is the condition where two electrically separate circuits cannot be connected because the peaks (positive and negative) on the ac voltage sine waves of the circuits do not occur simultaneously. Sometimes this is can be easily corrected because the conductors on the two three-phase circuits are connected differently at the place where they are to be tied. However for some 69 kV circuits, the out-of-phase condition is caused by the way transformers supplying the separate circuits are internally connected. It is generally not cost effective to correct for this condition as it would require that an additional three-phase transformer be installed on one of the circuits to shift its phasing to match the other circuit.

MPS reported that it fuses taps off of three-phase circuits to maximize isolation of tap faults and provide better reliability.

MPS has a comprehensive set of thermal ratings tables for its lines and substation equipment, including instrumentation. Such standards are important, as lines and equipment are comprised of many components. If any of these components experience conditions more extreme than those intended in their design and construction, line or equipment failure could occur.

In general, Liberty found MPS's planning practices to be adequate. MPS could improve some areas; for example, it has somewhat informal planning criteria and some of the load forecasting techniques employed are simplistic. MPS does not analyze its distribution system for potential voltage problems. MPS should consider using voltage software to predict distribution low or high voltage problems before they become customer complaints.

D. Inspections, Maintenance, and Vegetation Management

Liberty reviewed information supplied by MPS about the average age of its equipment such as poles, conductors, and transformers and did not identify any specific areas of concern.

MPS has been performing annual foot patrol inspections (using a tracked vehicle, where necessary) of its transmission system. It had used a contractor for inspecting, sounding, boring, and treating its transmission poles on a 5-year cycle. MPS appeared to be completing pole and cross arm repairs, replacements, and treatments as determined from these tests. After September 2003, MPS started using in-house resources and intensified its transmission pole inspection work so that it would have the entire system inspected within two years.

MPS has been systematically replacing its old distribution cedar poles and should complete this project in 2005. MPS has also been inspecting its other distribution poles and formalized this inspection process in September 2003 when it developed a comprehensive distribution line inspection program. Elements of this program include prioritizing circuits for inspection by known condition, age, customer count, and outage occurrences, sounding poles to detect internal defects, and the recording of 45 specific line, pole, and hardware inspection items in an electronic database. Under the new process, MPS has inspected 11 circuits (323 miles) out of 68 circuits (1,734 miles). MPS reported that it has addressed more than 90 percent of its reject poles. MPS said that it has not yet established the distribution line inspection cycle period, required to comply with the intent of NESC, but indicated that it is considering either a 5- or 10-year cycle.

MPS inspects its transmission and distribution substations bi-monthly, recording substation equipment conditions on inspection forms for evaluation by the Manager of Technical Services and the Engineering Department. It schedules repairs on any equipment that could jeopardize reliability. Additionally, MPS performs infrared inspections annually on all of its substation equipment to identify poor connections before they cause equipment damage or outages.

MPS maintains its transmission relays on a 2-year cycle, and maintains its distribution relays on a 4-year cycle. MPS periodically samples and tests insulating oil from its circuit breakers, transformers, and tap changers, tests its substation transformer fuses on a 5-year cycle, and periodically maintains its oil circuit breakers and reclosers. MPS does not periodically test its substation ground grids, nor does it perform periodic transformer insulation and winding tests. MPS should evaluate the possible reliability benefits that it could gain from performing periodic insulation power-factor tests and transformer turns-ratio tests on larger transformers, and periodic substation ground grid tests.

MPS's transmission right-of-way vegetation control program is on 5-year cycle (about 74 miles out of 368 miles per year, on average). However, budget considerations caused MPS to cancel this program for 2002. Also, MPS does not have a formal transmission right-of-way side clearance program. MPS performs roadside vegetation clearance on a 5-year cycle, and more frequently, where it cannot obtain adequate clearances. MPS said that it does not get easements for roadside clearance. Not obtaining such easements can create tree-related problems in cases where MPS cannot obtain adequate tree-line clearances, or if MPS provides adequate clearance, it is trimming trees on private property without landowner consent.

In the past, MPS conducted reactive "hot spot" trimming of trees on its distribution system. MPS's contractor trimmed only trees identified by MPS as burning or within 4 feet of conductors on its critical or worst performing circuits. Although MPS cancelled its herbicide application program in 2002, it then started using in-house crews for trimming on a 5-year cycle. However, MPS then found that it had to stop its cycle trimming to address hot spots on its six worst performing circuits. MPS indicated that starting in 2005 it intends to track circuit sections with inadequate clearances, and to trim trees on its distribution circuits on a 5-year cycle.

In general, MPS's transmission and distribution system inspection, pole testing, vegetation management, and equipment maintenance programs are adequate. However, the distribution system inspection should be periodic (as MPS said it intends to do) to comply with NESC.

E. Conclusions

Considering the resources available to MPS and its small size and low customer density, MPS appears to be doing a reasonable job in management of its T&D systems. It has applied some looping to its 69 kV transmission system, installed circuit tie switches, and has good transmission system pole and vegetation programs.

However, Liberty identified several important issues related to MPS's distribution reliability and maintenance programs. The following are brief discussions of these issues.

- Although MPS's distribution cedar pole replacement program and the new, intensified, and specific distribution inspection and pole test program are good, the programs do not fully comply with paragraphs 121 and 214 of the NESC, which requires total-system, periodic inspection and tracking of identified defects. Liberty agrees with MPS that it should implement a formal and periodic distribution circuit inspection and repair program, including tracking of defects until repaired. However, it should also include pole treatment in its pole testing program, which would extend useful pole life.

- MPS brought tree trimming in-house and thus has the capability to perform work on lines and tree trimming with some of the same crews. Liberty agrees with MPS that, for long-term reliability, it should implement a proactive 5-year tree trimming cycle on its distribution circuits while performing hot spot trimming on its worst performing circuits. It should also determine the necessity of obtaining easements for roadside trimming.

- MPS is not analyzing the causes of its substation bus outages, nor is it analyzing the trends in the failure of line equipment causing circuit outages. MPS should analyze the root causes for bus lockouts and identify common circuit equipment failure modes, and take actions as required to minimize outages.

Liberty also identified the following minor issues related to MPS's distribution reliability and maintenance programs.

- MPS forecasts loads on the basis of simple trends using average weather conditions. It should consider the use of loads in its system studies based on a probabilistic expectance of occurrence. This will provide more accurate investment timing.

- MPS does not have reliability target levels. It should determine what level of reliability it should provide to its customers and formalize its reliability criteria.

- MPS does not analyze its worst performing circuits for corrective actions required to improve reliability. It should consider the implementation of a worst performing circuit reliability program.

- MPS performs only oil testing on its substation transformers. It should evaluate the benefits of periodic transformer winding and insulation tests.

- MPS does not have software to predict high or low voltage problems on its distribution system. It should consider using software to determine if high or low voltage problems exist in its system.

V. Eastern Maine Electric Cooperative (EMEC)

A. Budgeting, Expenditures, and Other Issues

RUS's (Rural Utilities Services) guidelines determine many of EMEC's practices, including its capital and O&M spending. EMEC reported that it also bases its capital budgeting on the short- and long-term studies that project customer voltages, and thus, indirectly, system reliability. EMEC recently emerged from a long period of bankruptcy and had to obtain waivers from the RUS to lower its debt coverage ratio. Moreover, EMEC's future budgets appear to be low when viewed simply from a historic perspective.

Every three years, the RUS evaluates EMEC's conformance to the RUS Bulletin "Electric Operations and Maintenance." The ratings are "1" for unsatisfactory, "2" for acceptable but could be improved, and "3" for satisfactory. The RUS appears to perform both detailed desk and field audits on all aspects of system, construction and maintenance. For 2000-2003, RUS rated EMEC as "3" in all categories except service interruptions where the RUS rated EMEC a "2". Liberty notes that this rating was an improvement over the 2000 evaluation in which RUS rated EMEC as a "1." The RUS does recognize the rural nature of the EMEC system and the requirement for long radial distribution lines.

Distribution capital expenditures were lower in 2002 when compared to previous years. In 1999 and 2000, EMEC spent a large amount acquiring meters for its automatic meter reading (AMR) program and is now about 80 percent complete towards full AMR. EMEC attributed the remainder of the difference to the timing of capital projects.

B. System Reliability

During 2002, EMEC's customers experienced an average of about 20 hours of total service interruption time. The annual average customer interruption time has been between 10 and 20 hours for the last five 5 years. RUS's guidelines indicate that average annual customer outage should be 5 hours or less. EMEC reported that if it excluded outages caused by its power suppliers, extreme storms, and prearranged outages, the 2002 average outage time was a little more than 8 hours, still exceeding the RUS's guideline. While the RUS also highlights this in their report, they recognize that EMEC is very rural and has long radial distribution lines.

EMEC records the causes of sustained outages. The most prevalent causes recorded have been trees and major storms. EMEC reviewed its outage data and found that it classified many outages as trees or major storms; however, upon further investigation it found that equipment failures were involved. EMEC also states that they believe at least some of the increase in outages was due to better reporting.

EMEC also experienced a substantial number, about 20 per year, of substation bus outages. These bus outages caused sustained outages on multiple circuits fed by a substation. Up until 2003, power supplier transmission caused the majority of the bus outages. In 2003, however, EMEC's transmission or substation equipment caused most of the bus outages. EMEC should perform root cause analysis of these outages both on and off of its system.

EMEC reported that it fuses its taps off of feeder circuits. This is important for maximizing the isolation of faulted line sections and minimizing the number of customers affected by a fault.

C. System Planning, Design, and Equipment Ratings

EMEC reported that it primarily bases its short-term (4 years) and long-term (20 years) system planning capacity on studies for maintaining system voltages within RUS and ANSI standards and without having to install more than one set of line voltage regulators. The results of these studies could require converting lower voltage distribution circuits to higher voltages or maintaining minimum percent power-factor levels. To improve reliability of urban circuits, EMEC separates urban and rural circuits on the same poles. EMEC does not perform power flow studies because the system apparently has adequate capacity.

EMEC adjusts its load forecasts for the planning studies using the average of the heating degrees and cooling degrees for the previous five years. This could result in under-estimating future loads. EMEC uses voltage drop calculations for planning purposes.

EMEC said that it does not need to construct new transmission lines. However, it plans to construct two new 25 kV distribution substations and upgrade some distribution circuits to 25 kV. Currently, the southern portion of the MPS system feeds approximately 3 MW of EMEC firm load via a 44 kV transmission line. The New Brunswick system feeds the remaining 16 MW of firm load via a 48-mile 69 kV transmission line. EMEC looked at looping this system, but this appeared to be too costly. A partial solution previously considered envisioned backing up approximately 7 MW load by the construction of a 138 kV tie line to New Brunswick. Its cost was determined to be approximately $7.5 million. EMEC also states that they do not expect to reach 25 MW of firm load until some time beyond 2020.[8] Liberty suggests that as EMEC rebuilds its distribution circuits to 25 kV, it investigate opportunities to balance the loads among its two transmission sources in a manner commensurate with their respective reliability contribution to maximize overall reliability to EMEC's customers.

Liberty also notes here that the EMEC system relies on transmission providers (MPS and New Brunswick) for that function. EMEC should report its outage data to the Commission (and to the other utilities) so that the Commission knows and can monitor the effect of each transmission provider on EMEC's service quality. EMEC should also become more involved in northern Maine transmission solutions rather than accepting the transmission provided by other systems that may be best for only the transmission provider.

EMEC designs and operates its system to a 0.95 power-factor load. The RUS required minimum power-factor requirements are 0.95 power-factor lagging for residential customers and 0.80 power-factor lagging for industrial customers. EMEC should study the cost effectiveness of improving its system power factor levels because EMEC reported that it has 10 to 11 percent system losses and its system is voltage limited.

[8] Many utilities commonly use 25 MW as the acceptable amount of load that can be lost for a single contingency without backup or alternate feed.

D. Inspection, Maintenance, and Vegetation Management

Liberty reviewed information from EMEC concerning equipment age, rating, and inspection. Liberty did not identify any significant areas of concern with the exception that EMEC does not appear to meet the RUS requirement of 3-year line inspections. EMEC inspected 39 1½-mile line sections in 1999 but did not report any other regular system inspections. EMEC indicated that linemen perform ad hoc inspections when they are not performing other work. This is also not in compliance with NESC requirements.

Although EMEC does not have a "circuit looping" criterion, it has designed in the ability to tie distribution circuits at some locations. EMEC also has under-built (double) circuits on some pole lines to provide isolation of urban customers from rural line exposure (i.e., one feeds urban circuits and the other goes out farther to feed rural circuits and in general, outages on the rural circuits will not impact urban customers). Given the rural nature of its system, Liberty believes that is all that EMEC can economically provide to its customers.

EMEC has over 1,200 miles of overhead distribution (4 kV to 25 kV) serving its 3,000 square mile, largely forested territory. EMEC indicated that when it builds a new line, it uses ground line vegetation control that is good for about 25 years before additional tree trimming may be required. Nevertheless, in recent years EMEC performed vegetation control on only about 90 miles per year, which may indicate a 15-year cycle. The increased vegetation control in 2004 may indicate a 10-year regular cycle. Many utilities have regular 4- or 5-year tree trimming cycles. As noted above, EMEC reported that the most common causes of sustained outages were trees and major storms (which, in part, could also relate to trees in proximity of lines).

E. Conclusions

Considering EMEC's small size and rural service territory, Liberty has no major concerns with the manner that EMEC addresses the reliability of its T&D system with the exception that the annual average customer-outage time is still relatively high. Although still above RUS criteria, EMEC has reduced outage times in recent years. EMEC should continue its efforts to find cost-effective methods of reducing the average interruption duration.

However, Liberty found important issues related to EMEC's distribution system. The following are brief discussions of these major issues:

- EMEC's distribution circuit inspection programs do not fully comply with paragraphs 121 and 214 of the NESC, which requires total-system, periodic inspection and tracking of identified defects. EMEC should implement a formal and periodic distribution circuit inspection and repair program, including tracking of defects until repaired. It should also include pole treatment in its pole testing program, which would extend useful pole life. However, as required by the RUS, EMEC performs and records some periodic inspections.

- EMEC could improve system reliability with a more robust vegetation management program.

- EMEC has experienced about 20 substation bus outages per year. EMEC should perform a root cause analysis of its substation bus outages and determine actions to minimize these outages.

- EMEC has no on-system generation; a single 44 kV line from the southern part of the MPS system partially supplies its energy. This line has a significant effect on EMEC's reliability. Liberty suggests that EMEC report to the Commission and MPS supply outage data for determining and monitoring the reliability effect on EMEC. EMEC should be proactive in its involvement with MPS' transmission planning and changes that could affect EMEC.

Liberty also identified the following minor issues related to EMEC's distribution system:

- As EMEC rebuilds its distribution circuits to 25 kV, it should investigate opportunities to balance the loads among its two transmission sources in a manner commensurate with their reliability to maximize reliability to EMEC's customers.

- EMEC uses average weather over the previous five years to adjust its load forecasts. It should consider the use of loads in its system studies based on a probabilistic expectance of occurrence. This will provide more accurate investment timing.

- EMEC follows RUS requirements for allowed power-factor levels. It should evaluate the loss reduction and voltage improvements associated with increasing the design load power factor to greater than RUS levels.